NORTH CAROLINA
DIVISION OF AIR QUALITY

Preliminary Determination / Application Review

Issue Date: xx

Region: Asheville Regional Office
County: Rutherford
NC Facility ID: 8100028
Inspector's Name: Mike Parkin
Date of Last Inspection: 06/17/2016
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Cliffside Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Cliffside Steam Station
573 Duke Power Road (SR 1002)
Mooresboro, NC 28114

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02D .0501(c), .0503, .0519, .0521, .0530, .0536, .0606, .1100, and 02Q .0700
NSPS: N/A
NESHAP: N/A
PSD: Major Modification for CO and VOC
PSD Avoidance: N/A
NC Toxics: Yes
112(r): N/A
Other: N/A

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Steve Hodges Environmental Coordinator (828) 657-2339 573 Duke Power Road Mooresboro, NC 28114	David Barnhardt Manager (828) 657-2001 573 Duke Power Rd Mooresboro, NC 28114	Daniel Markley Lead Environmental Specialist (704) 382-0696 526 South Church Street Charlotte, NC 28202-1006

Application Data

Application Number: 8100028.16B
Date Received: 12/02/2016
Application Type: Modification
Application Schedule: PSD

Existing Permit Data

Existing Permit Number: 04044/T40
Existing Permit Issue Date: 07/20/2017
Existing Permit Expiration Date: 06/30/2022

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2015	617.26	1176.38	12.90	541.01	178.96	16.29	9.99 [Hydrogen chloride (hydrochlori]
2014	1253.94	2106.74	19.19	1149.66	269.79	19.63	14.65 [Hydrogen chloride (hydrochlori]
2013	872.92	1611.86	18.38	1173.09	254.08	21.60	16.33 [Hydrogen chloride (hydrochlori]
2012	316.21	458.51	15.51	309.05	203.55	18.67	14.81 [Hydrogen chloride (hydrochlori]
2011	310.05	712.01	32.19	631.70	545.97	42.93	35.61 [Hydrogen chloride (hydrochlori]

Review Engineer: Rahul Thaker **Review Engineer's Signature:** **Date:** August 17, 2017	**Comments / Recommendations:** **Issue** 04044/T41 **Permit Issue Date:** xx **Permit Expiration Date:** xx

1.0 Purpose of Application

Duke Energy Carolinas, LLC, Cliffside Steam Station (hereinafter "DEC"), submitted a Prevention of Significant Deterioration (PSD) application to add natural gas firing capability to the permitted coal/No. 2 fuel oil-fired electric utility steam generating units (EGUs) [ID Nos. ES-5 and ES-6]. After the modification, Unit 5 will be able to burn up to 40 percent (hourly heat input basis) natural gas alone or in combination with coal, or 100 percent coal (hourly heat input basis), and Unit 6 will be able to burn 100 percent natural gas (hourly heat input basis), 100 percent coal (hourly heat input basis), or any combination of these fuels. The actual amount of fuel mix fired in each boiler will depend upon cost, availability, and demand. Basically, the proposed change to allow natural gas firing provides DEC additional fuel firing flexibility. The applicant has argued that the proposed project only affects the type of fuel fired in each boiler and it does not affect the permitted heat input rate for each EGU (6,080 million Btu/hr maximum heat input rate for Unit 5 and 7,850 million Btu/hr maximum heat input rate for Unit 6). Moreover, it does not modify the operations of any other permitted sources (other than Units 5 and 6) at the facility. That is, it will not cause debottlenecking for the operations of any other permitted equipment.

The application has been deemed "complete" for PSD as of 12/12/2016. As requested by the applicant, North Carolina Division of Air Quality ("DAQ") will process the application using the procedure in 15A NCAC 02Q .0501(c)(2) and .0504, satisfying the permitting requirements in 02D .0530 (PSD) and 02Q .0300 (construction and operation permits). The applicant will be required to submit another application within 12 months of commencement of operation of the above modified sources, pursuant to 02Q .0500 "Title V Procedures".

2.0 Existing Facility Operations

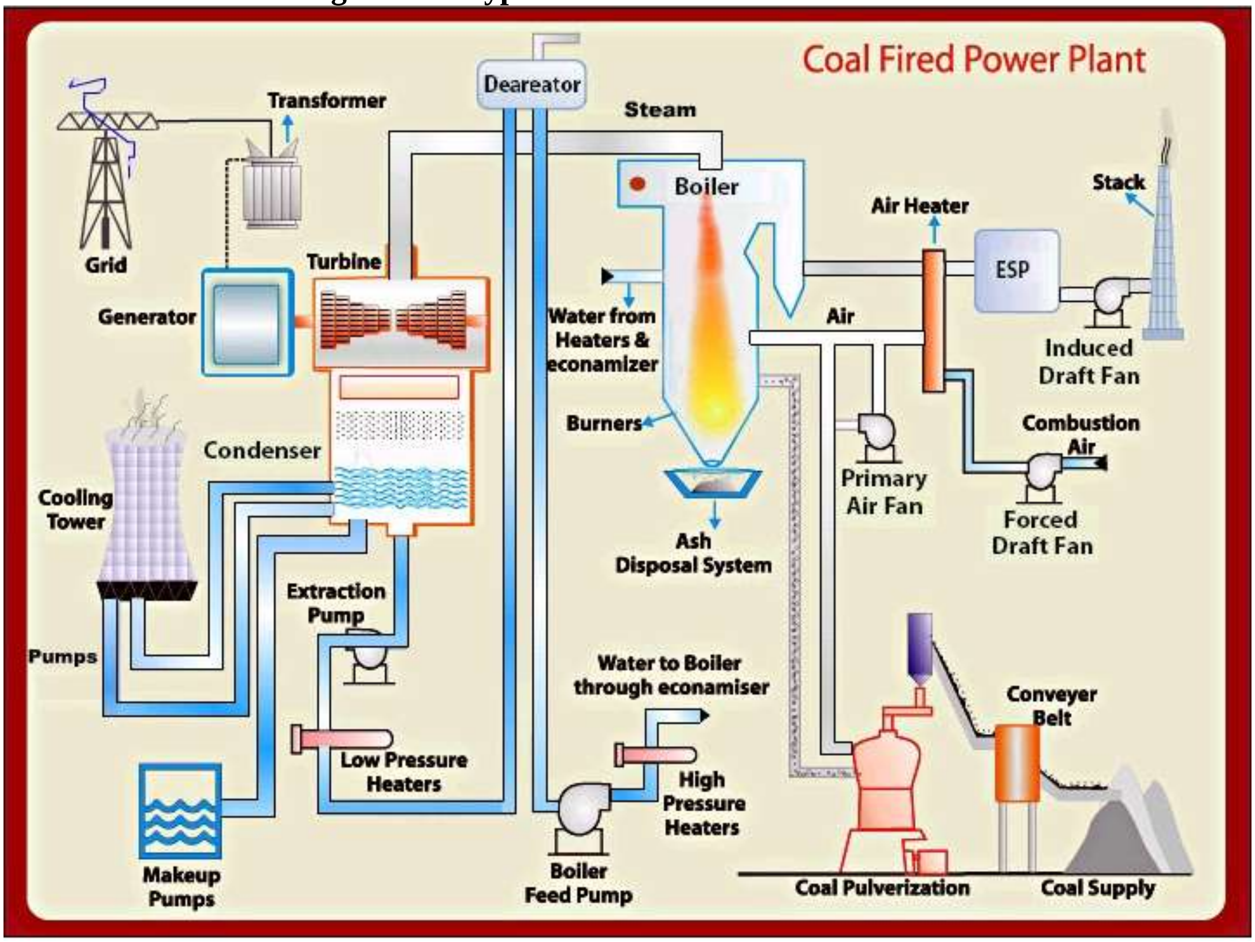
DEC owns and operates the Cliffside Steam Station (also known as, Rogers Energy Complex), located on the Rutherford-Cleveland County border in North Carolina. The Cliffside Station is comprised of Units 5 and 6 (currently permitted to fire coal and No. 2 fuel oil), auxiliary boilers, emergency generators/fire pumps, cooling tower, and coal, fly ash, limestone, and gypsum storage and handling equipment, in addition to myriad of insignificant activities of different types.

Unit 5 is equipped with pollution control equipment consisting of selective catalytic reduction (SCR) system, flue gas ash conditioning system, portable hydrated lime dry sorbent injection system, electrostatic precipitators (ESPs), and flue gas desulfurization system (FGD), for pollution control. Unit 6 pollution control devices include an SCR, spray dryer absorbers, baghouses, and FGD. The facility's primary business activity is classified under the Standard Industrial Classification code 4911 "Electric Services"[1]. Under North American Industrial Classification System (NAICS), it can be classified under code 221112 "Fossil Fuel Electric Power Generation".

The following schematic in Figure 2-1 includes major components of a typical coal-fired steam-electric power plant.

[1] Includes establishments engaged in generation, transmission and/or distribution of electric energy for sale.

Figure 2-1: Typical Steam-Electric Power Plant



3.0 Project Description

3.1 Site/Regional Description

The Cliffside Station is located along the Cleveland and Rutherford County border, approximately 5 kilometers (km) south of Cliffside, North Carolina. The approximate Universal Transverse Mercator (UTM) coordinates are Zone 17, 430.620 km east and 3897.005 km north (North American Datum 1983 – NAD83) at an elevation of approximately 775 feet above mean sea level. It is located along the foothill, Piedmont transition of North Carolina and the terrain surrounding the site can be considered gently rolling with no terrain features above stack top elevation. Figures 3-1 and 3-2 below exhibits the facility location, and the site layout and surrounding topography, respectively.

Figure 3-1: Facility Location

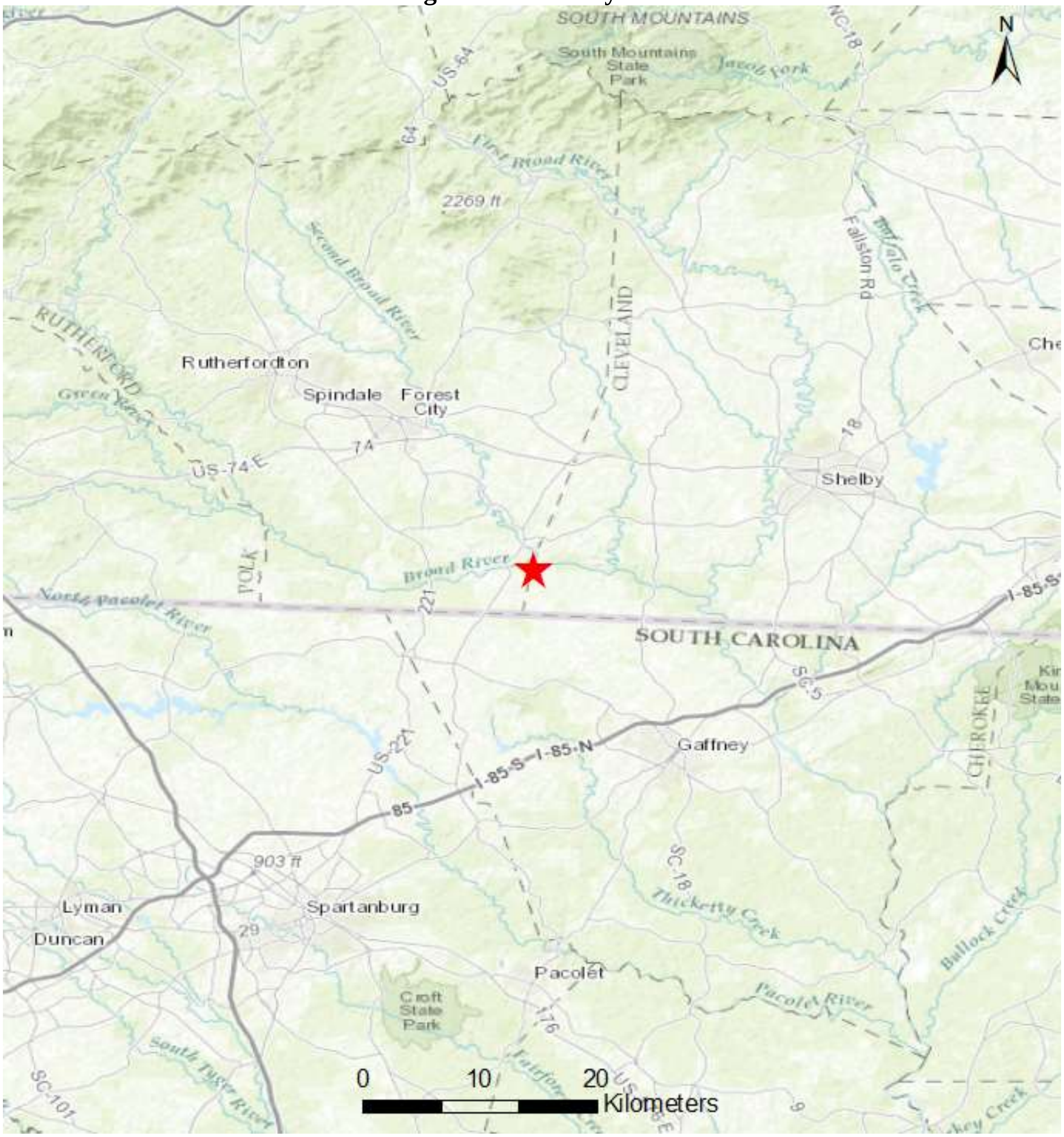
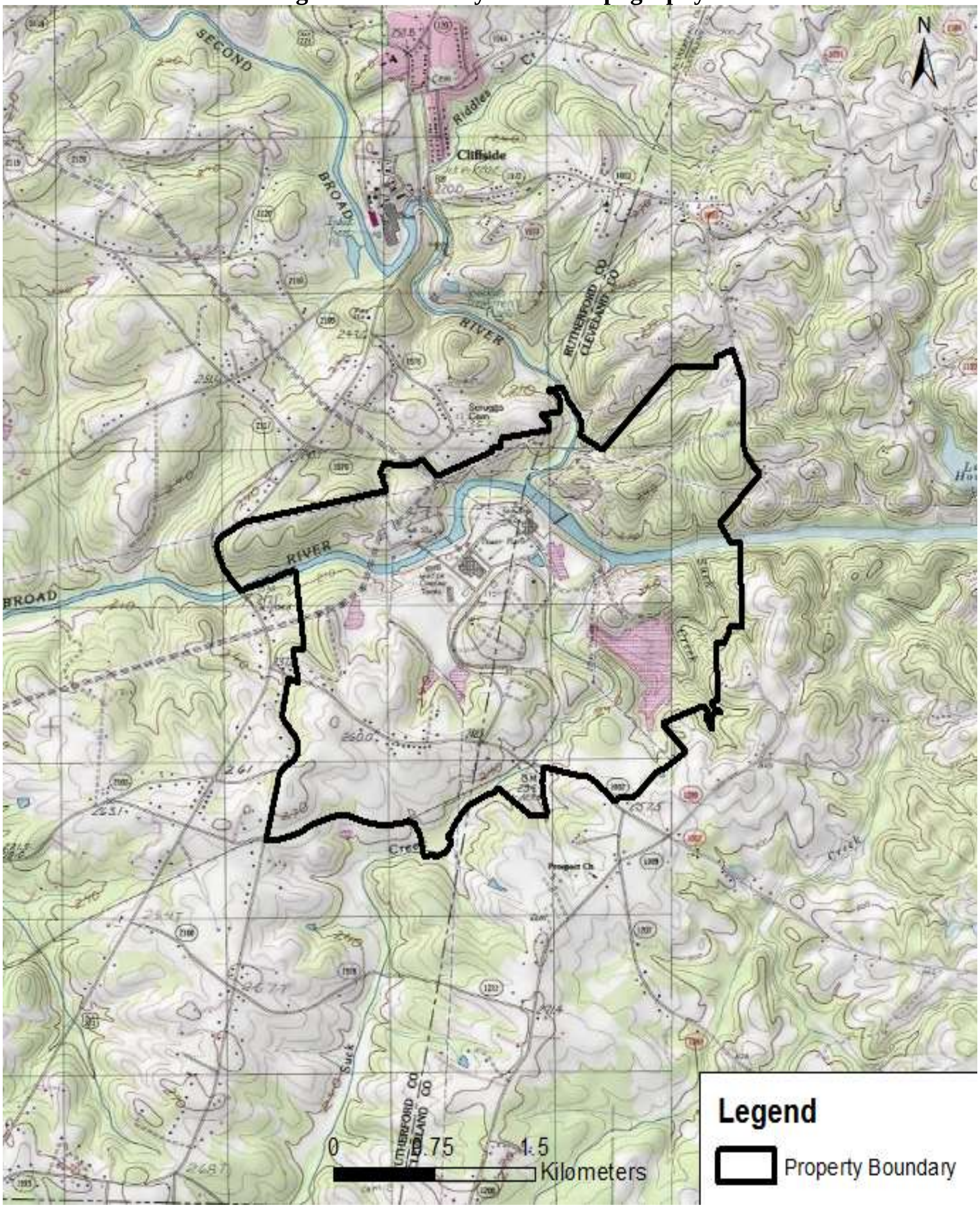


Figure 3-2: Site Layout and Topography



Current air quality designations for Rutherford County with respect to various National Ambient Air Quality Standards (NAAQSs) are described below in Table 3-1 in accordance with 40 CFR 81.334 “North Carolina”:

Table 3-1: Attainment Status Designations

Pollutant	Designations
PM_{10}	Attainment (Both 1987 (annual) and 2012 (24-hour) NAAQSs)[2]
$PM_{2.5}$	Unclassifiable/Attainment (Both 2006 (24-hr) and 2012 (annual) NAAQSs)
Sulfur Dioxide	Attainment (1971 (annual) NAAQS), Not Designated Yet (2010 (1-hr) NAAQS)
Nitrogen Dioxide	Attainment (1971 (annual) NAAQS)[3], Unclassifiable/Attainment (2010 (1-hr) NAAQS)
Carbon Monoxide	Unclassifiable/Attainment (1971 (1-hr and 8.hr) NAAQS)[4]
Ozone	Unclassifiable/Attainment (2008 (8-hr) NAAQS), Not Yet Designated (2015 (8-hr) NAAQS)
Lead	Unclassifiable/Attainment (2008 (3-month) NAAQS)

In summary, Rutherford County is in attainment or unclassifiable/attainment of all promulgated NAAQS. Further, this County is considered a Class II area with ambient air increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_2. For Class I area standpoint, the closest (Class I) area from this facility is Linville Gorge National Wilderness Area, which is located approximately 40 miles (65 kilometers) northwest of the facility.

3.2 Project Sources

DEC is proposing to modify the permitted Unit 5 (ES-5) and Unit 6 (ES-6) EGUs to add natural gas firing capability to its existing coal/No. 2 fuel oil-burning capability. The permitted heat input rates are 6,080 million Btu/hr (Unit 5) and 7,850 million Btu/hr (Unit 6).

PSNC (Public Service of North Carolina) will provide for interruptible transport of natural gas to Units 5 and 6 via a new pipeline, which it will construct, lateral to the PSNC’s Kings Mountain to Ashville intrastate pipeline currently being built. Refer to the DEC letter[5].

The letter specifies that the proposed project at the Cliffside facility comprises of burner modifications, igniter modifications, gas piping and control system additions and logic changes, at a total cost of $56 million.

The Permittee defines the purpose of the project is to provide additional fuel flexibility (natural gas) depending upon the price of fuel (coal v. natural gas), without changing the heat input capacity of each of the units. The letter states that this dual fuel optionality (DFO) project “will help hedge against future coal and gas cost uncertainties and will provide the ability to maximize benefit from short-term (daily/weekly) fuel price variability”. Further as per the letter, “the DFO project will also provide overall environmental benefits, including a 40% reduction of CO_2, nearly 100% reduction of mercury and SO_2, as well as elimination of ash as a by-product, when running on gas.” With respect to the existing coal capability, the Permittee reflects that coal burning especially in Unit 6 depends upon “coal transportation prices, [availability of] single rail transportation [to the Cliffside facility], and natural gas market prices.”

After the modification, Unit 5 can burn up to 40 percent (hourly heat input basis) natural gas either alone or in combination with coal, or 100 percent coal (hourly heat input basis). Unit 6 will be able to burn 100 percent natural

[2] Assumed. Rutherford County has been designated unclassifiable / attainment for more stringent PM2.5 NAAQSs for both 24-hr and annual averaging periods.
[3] The same 1971 NO_2 NAAQSs (primary and secondary) for annual averaging period were retained in 1985, 1996, 2010 and 2012.
[4] The same 1971 CO NAAQSs (primary) for both 1-hr and 8-hr averaging periods were retained in 1985, 1994 and 2011.
[5] Duke Energy Carolinas, LLC’s “Notice of Natural Gas Addition to Rogers Energy Complex (Cliffside) Unit 5 and 6, Docket No. E-7, Sub 790”, October 11, 2016 Letter from Lawrence B. Somers, Deputy General Counsel, Duke Energy, Charlotte, NC, to Chief Clerk, North Carolina Utilities Commission, Raleigh, NC.

gas (hourly heat input basis), 100 percent coal (hourly heat input basis), or any combination of these fuels. As per the Permittee, during typical operation, natural gas usage will primarily be in Unit 6 and the balance of gas supply, up to 10 percent, will be used in Unit 5. However, if Unit 6 is to shut-down for maintenance, Unit 5 can increase gas usage up to 40 percent of total capacity on a short-term basis. The Permittee clarifies that this 10 percent fuel firing limitation for Unit 5 is due to physical limitation of the pipeline and not due to capacity of gas burner. Finally, as per the Permittee, the actual fuel mix fired in the subject boilers will be based upon cost, availability, and demand.

Natural gas does not contain appreciable amount of fly ash, sulfur, or mercury constituents. DEC wishes to not operate those specific air pollution control devices which would target collection of these constituents when firing solely natural gas. DEC argues that the control equipment would consume parasitic load, requiring additional fuel consumption for the same electrical output, while providing no environmental benefit. Thus, for Unit 5, DEP has requested the ability to not operate the ESP, the flue gas ash conditioning systems, and the wet FGD, when firing solely natural gas. Similarly, for Unit 6, DEC has requested the ability to not operate the spray dryer absorber, baghouse, and wet FGD, while firing solely natural gas. However, it needs to be noted that components of the above control equipment may still be operated in a limited fashion for equipment protection, but not as originally designed. Flue gas will still exhaust through currently permitted stacks, and NOx emission control (e.g., selective catalytic reduction system) and existing continuous emissions monitoring systems (CEMS) will remain active while firing solely natural gas.

3.3 Project Schedule

The Permittee has proposed the date of commencement of construction to be December 2017. This date is contingent upon DAQ completing the processing of the PSD application and a reaching a favorable decision (i.e., to grant a permit for the project described above).

3.4 Project Emissions

Emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, lead, sulfuric acid mist, GHG, and some NC-regulated air toxics are expected due to the burning of natural gas alone or in combination with coal, in these existing EGUs. The changes in emissions have been discussed in detail in Section 4.0 and summarized below:

- Particulate Matter (PM): -8.74 tons/yr (TPY) [decrease]
- PM_{10}: -141.34 TPY [decrease]
- $PM_{2.5}$: -122.91 TPY [decrease]
- SO_2: -789.02 TPY [decrease]
- NOx: 17.60 TPY [increase]
- CO: 1,713.96 TPY [increase]
- VOC: 124.04 TPY [increase]
- Lead: -0.03 TPY [decrease]
- Sulfuric Acid Mist: -24.02 TPY [decrease]
- GHG (as CO_2e): -2,157,188 TPY [decrease]

Each of these EGUs are exhausted through a dedicated 574 feet stack. The exhaust parameters include exit velocities of 16.8 ft/sec (Unit 5) and 25.5 ft/sec (Unit 6), and exit temperatures of 125°F (Unit 5) and 128.3°F (Unit 6).

4.0 Regulatory Applicability

The modified Units 5 and 6 are subject to the following requirements:

15A NCAC 02D .0501(c) “Compliance with Emission Control Standards”

This standard requires that any source of air pollution shall be operated with such control or in such a manner that the source shall not cause the ambient air quality standards of 15A NCAC 02D .0400 to be exceeded at any point beyond the premises on which the source is located.

Unit 5 is subject to this requirement: sulfur dioxide emission standard of 1.6 lb/million Btu over a 24-hour block average, when using the FGD. Unit 5 demonstrates compliance with this limit via an SO_2 CEMS. Due to negligible sulfur content (as compared to coal or No. 2 fuel oil), emissions of SO_2 are expected to decrease significantly. Therefore, Unit 5 will continue to comply with this limit after modification.

The Permittee has requested to modify this condition to state that operation of SO_2 control technology is not required during periods when only natural gas is fired in Unit 5. SO_2 emissions are expected to be well below this limit when firing 100 percent natural gas in Unit 6. The SO_2 CEMS will continue to operate and assure compliance with the above limit regardless of whether the advanced controls are in operation. The DAQ will allow the Permittee to not operate the existing SO_2 control technology (FGD) when burning only natural gas in Unit 5 boiler.

Unit 6 is currently not subject to the requirements in 02D .0501(c).

<u>15A NCAC 02D .0503 "Particulates from Fuel Burning Indirect Heat Exchangers"</u>

This regulation applies only to Unit 6, specifically with respect to particulate emissions, which are calculated using the following equation:

$$E = 1.090 \times Q^{-0.2594}$$

Where:

E = allowable emission limit for particulate matter in lb/million Btu
Q = maximum heat input in million Btu/hr (total for all permitted indirect heat exchangers)

Based on the maximum heat input rate of 7,850 million Btu./hr, allowable emission rate for Unit 6 has been estimated to be 0.10 lb/million Btu, as per the current permit. Burning natural gas alone or in combination with coal should have negligible impact on compliance with the standard. Natural gas is expected to have no ash or ash residues as compared to coal. Further, the Unit 6 is subject to the requirements in NSPS Subpart Da (See section on applicability of 15A NCAC 02D .0524 below), which has a more stringent emission standard for PM. In summary, compliance is expected for Unit 6 with the requirements in 02D .0503.

Unit 5 is subject to the requirements in 15A NCAC 02D .0536 (See section below); therefore, it is not required to comply with the standard in 02D .0503.

<u>15A NCAC 02D .0519 "Control of Nitrogen Dioxide and Nitrogen Oxides Emissions"</u>

This regulation applies to Unit 5 only and its emissions of nitrogen oxides shall not exceed the limit calculated by the equation:

$$E = [(Ec)(Qc) + (Eo)(Qo)]/Qt$$

Where:
E = the emission limit for combined coal and oil or gas in lb/million Btu
Ec = 1.8 lb/million Btu heat input for coal only
Eo = 0.8 lb/million Btu heat input for oil and gas
Ec = the actual coal heat input to the combination in Btu/hr
Eo = the actual oil and gas heat input into the combination in Btu/hr
Qt = Qc+Qo and is the actual total heat input

As per the current permit, Unit 5 assures compliance with this limit via NO_x CEMS on a 24-hour block average. This boiler will continue to comply with the above NOx standard when burning natural gas only, coal only, or natural gas in combination with coal, and will also be required to continue complying with the above monitoring requirement. The emissions rates for NOx when firing coal and natural gas are 0.126 lb/million Btu and 0.167 lb/million Btu, respectively. The coal combustion emission rate is the actual emission rate as measured by the CEMS during the selected baseline period (March 2013 through February 2015) respectively, and has been used to estimate projected actual emissions. The natural gas combustion emission rate (factor) for a tangentially-fired boiler is taken from AP-42 (Section 1.4 Natural Gas Combustion). Compliance is expected.

Unit 6 is subject to the requirements in 15A NCAC 02D .0524 (See section below), specifically for NOx emission standard; therefore, it is not required to comply with the standard in 02D .0519.

15A NCAC 02D .0521 "Control of Visible Emissions"

This rule applies to all fuel burning sources and other processes that may have visible emissions. For sources manufactured as of July 1, 1971, visible emissions shall not be more than 40% opacity averaged over a six-minute period. The 40% opacity limit may not be exceeded more than 4 times in 24 hours and the percent of excess emissions shall not exceed 0.8 percent of total operating hours.

Unit 5 is currently subject to this emission limit and is not expected to have increased visible emissions due to the addition of natural gas firing capability; therefore, Unit 5 is expected to continue demonstrating compliance with this limit post project. Unit 5 is currently required to monitor its visible emissions when burning coal or No. 2 fuel oil, using the continuous opacity monitoring system (COMS). In lieu of COMs, the Permittee can install and monitor particulate emissions from Unit 5 by installing a PM continuous emissions monitoring system (CEMS).

If the Permittee decides to install a PM CEMS, opacity monitoring is not required. The Permittee will continue to be subject to the above COMs and CEMS requirements when burning natural gas only or natural gas in combination with coal.

Unit 6 is subject to a 20% opacity limit under NSPS (See section below); thus, it is exempt from this standard.

15A NCAC 02D .0524 "New Source Performance Standards"

Unit 5 is currently not subject to any NSPS; however, Unit 6 is subject to Subpart Da "Standards of Performance for Electric Utility Steam Generating Units, specifically with respect to the requirements for PM, SO_2, and NOx emissions. All applicable requirements have been properly included in the current permit for this Unit 6 for existing coal burning operations.

If either of the Units are deemed "modified" or "reconstructed" for the proposed project, it may be subject to Subpart Da or Subpart TTTT "Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units", or both. It should be stated here that Subpart Da covers pollutants PM, SO_2, and NOx, while Subpart TTTT covers pollutant CO_2.

With the proposed modifications (both physical and operational) to both Units 5 and 6, the Permittee has provided analysis under "modification" and "reconstruction" provisions in 40 CFR 60.14 and 60.15, respectively, as below.

Modification

Per §60.14(a), "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere."

For EGUs, the change in emissions are measured as maximum hourly emission rate prior to the change to maximum hourly emission rate after the change. Specifically, §60.14(h) provides that "no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change."

The following Table 4-1 provides the maximum pre- and post-change hourly emission rates for the pollutants regulated under these Subparts.

Table 4-1: NSPS Modification Analysis

Maximum Hourly Emission Rate: Pre-change v. Post-Change				
Regulated Air Pollutant	Unit 5		Unit 6	
	Pre-change	Post-change	Pre-change	Post-change
PM	182	182	118	118
SO_2	9,728	9,728	942	942
NOx	10,944	10,944	550	550
CO_2	1,191,680	1,191,680	1,609,250	1,609,250

The above table indicates the changes associated with natural gas firing whether alone or co-firing with coal in Units 5 and 6 are not expected to increase the respective maximum hourly emission rate for these regulated air pollutants. Therefore, modification in §60.14 is not triggered. Thus, none of these units become subject to NSPS Subparts Da or TTTT through "modified" source provision. However, as stated above, Unit 6 will continue to be subject to Subpart Da requirements as required currently under the "new" source provision.

Reconstruction

Per §60.15, an existing facility (i.e., source) becomes a "reconstructed" facility irrespective of change in maximum emission rate (pursuant to §60.14).

""Reconstruction" means the replacement of components of an existing facility to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part."

In accounting for the fixed capital cost for a facility, as per EPA, only the costs of engineering, purchase and installation of major process equipment, contractors' fees, and labor are to be included.

The applicant has estimated that the total fixed cost for the project (both Units 5 and 6) is $56 million which equates to approximately 2 percent of the fixed capital cost to construct a comparable new facility (consisting of both Units 5 and 6). Therefore, the proposed project does not trigger the reconstruction provision in §60.15 for any unit for Subpart Da or Subpart TTTT.

Litigation

This promulgated regulation in NSPS Subpart TTTT is currently litigated in the US Court of Appeals for the DC Circuit (USDC). As per the Order from the court dated April 28, 2017, the consolidated cases in State of North Dakota v. EPA have been held in abeyance for 60 days from this date. In addition, the litigating parities have been asked to file briefs by May 15, 2017, addressing whether the consolidated cases can be remanded to the EPA rather than held in abeyance at the court. Finally, the USDC on August 8, 2017 ordered to further keep the cases in abeyance for 60 days from this date, in addition to requiring EPA to file status reports every 30 days from this date.

<u>15A NCAC 02D .0530 "Prevention of Significant Deterioration"</u>

United States (US) Congress first established the New Source Review (NSR) program as a part of the 1977 Clean Air Act Amendments and modified the program in the 1990 amendments. The NSR program includes requirements for obtaining a pre-construction permit and satisfying all other preconstruction review requirements for major stationary sources and major modifications, before beginning actual construction for both attainment areas and non-attainment areas. The NSR program for attainment and non-attainment areas are called "Prevention of Significant Deterioration" (PSD) and "Non-attainment New Source Review" (NAA NSR), respectively. The NSR focuses on industrial facilities, both new and modified, that create large increases in the emissions of specific pollutants.

The basic goal for PSD is to ensure that the air quality in attainment areas (e.g., Rutherford County, NC, for PM_{10}, $PM_{2.5}$, NO_2, SO_2, CO, ozone, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth.

Under PSD, all major new or modified stationary sources of air pollutants as defined in §169 of the CAA must be reviewed and permitted, prior to construction, by EPA and/or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28 named source categories (e.g., "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input"), which emits or has a potential to emit (PTE) of 100 tons per year of any "regulated NSR pollutant", or any other stationary source (i.e., other than 28 named source categories), which emits or has the potential to emit 250 tons per year of any "regulated NSR pollutant".

Pursuant to the Federal Register notice on February 23, 1982 (47 FR 7836), North Carolina (NC) has a full authority from the US Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. NC's State Implementation Plan (SIP) - approved PSD regulations have been codified in 15A NCAC 02D .0530, which implement the requirements of 40 CFR 51.166 "Prevention of Significant Deterioration of Air Quality". The version of the CFR incorporated in the NC's SIP is that of May 16, 2008, with a few exceptions and it does not include any subsequent amendments or editions to the referenced material. Refer to Table 1 to §52.1770. However, it should be noted that on September 1, 2013, NC adopted changes to its PSD regulation incorporating explicitly both PM_{10} and $PM_{2.5}$ increments; however, these changes have been disapproved by the EPA on September 14, 2016 (81 FR 63107). The DAQ has initiated the process to amend its PSD regulation to conform to the PM2.5 increment and major source baseline date, as included in EPA's October 20, 2010 rule (75 FR 64864) responding to the above EPA disapproval.

The DEC facility is an existing PSD major stationary source, classified under the category of "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input". As stated above, this category is one of the 28 named source categories. The facility emits or has a potential to emit 100 tons per year for several regulated NSR pollutants; PM_{10}, $PM_{2.5}$, SO_2, NO_x (as NO_2), CO, and VOC.

Because this existing facility is considered a major stationary source, any modification to an existing major source resulting in both significant emission increase and net significant emissions increase for a regulated NSR pollutant, is subject to PSD review and must meet appropriate review requirements.

The Permittee has performed a PSD applicability analysis for the project for determination of whether the project results in an emission increase of any regulated NSR pollutant above the applicable significance thresholds. Using the "actual-to-projected actual test" in §51.166(a)(7)(iv)(c), the Permittee has performed calculations for baseline actual emissions (pre-change) [BAE] and projected actual emissions (post-change) [PAE] for each regulated NSR pollutant expected to be emitted from the modified EGUs, burning either coal, natural gas, or both.

As per the NC's SIP-approved regulatory provision in 02D .0530(b)(1), the Permittee can choose any consecutive 24-month within the five-year look-back period from the date of the receipt of the complete application to determine baseline actual emissions. The requirement also specifies that the DAQ Director can allow a different look-back period not to exceed 10 years immediately preceding the date of the receipt of the complete application, if the Permittee can demonstrate that it is more representative of normal source operation. The DAQ deemed this application complete on December 12, 2016. The Permittee selected a baseline period, a consecutive 24-month period, from March 2013 through February 2015, and estimated actual emissions (i.e., baseline actual emissions) for the existing emissions units (such as Units 5 and 6) for various pollutants. Thus, the selected baseline period meets the above requirement. The BAEs are estimated for each unit for various pollutants using the CEMS data (SO_2 and NOx), emissions factors[6], and stack test data.

[6] Section 1.1 "Bituminous and Subbituminous Coal Combustion" and Section 1.3 "Fuel Combustion", AP-42, EPA.

The PAEs for each of these units have been estimated based upon projected annual fuel usage and fuel mix, proposed BACT (CO and VOC), stack test data, emissions factors[7], EPRI report[8], and other data[9].

The following Table 4-2 provides a summary of change in emissions for the project:

Table 4-2: Emissions Changes Due to Proposed Project

Regulated NSR Pollutant	Baseline Actual Emissions Tons Per Year	Projected Actual Emissions Tons Per Year	Emissions Increase/Decrease Tons Per Year	Significant Emission Rate Tons Per Year	Major Modification Review Required?
PM	65.84	57.11	-8.74	25	No
PM_{10}	258.06	116.72	-141.34	15	No
$PM_{2.5}$	232.79	109.88	-122.91	10	No
SO_2	1,110.85	321.83	-789.02	40	No
NOx (as NO_2)	1,910.12	1,927.73	17.60	40	No
CO	1,244.53	2,958.49	1,713.96	100	Yes
VOC	19.44	143.48	124.04	40	Yes
Lead	0.13	0.09	-0.03	0.6	No
Sulfuric Acid Mist	81.72	57.70	-24.02	7	No
GHG as CO_{2e}	5,910,842	3,753,655	-2,157,188	75000	No

It should be noted that both BAE and PAE include emissions associated with startups, shutdowns, and malfunctions. In addition, the combustion emissions due to burning natural gas alone or in combination with coal are all stack emissions; hence, fugitive emissions are not expected. Although it can be argued that negligible fugitive emissions of methane (part of natural gas), one of GHG constituents, can occur due to possible leakage in natural gas pipeline infrastructure leading to the facility boilers (i.e., couplings, valves, piping joints, etc.); but they do not impact the conclusions drawn above with respect to which pollutants would need to go through PSD for the modification. Finally, the BAE and PAE for both PM-10 and PM2.5 include filterable and condensable portions, but for PM, the BAE and PAE estimate include only filterable emissions, pursuant to §51.166(b)(49)(i)(a).

As shown in the table above,

- The change in emissions for PM, PM_{10}, $PM_{2.5,}$ SO_2, lead, sulfuric acid mist, and GHG are negative (i.e., emissions decreasing). In addition, for NOx (as NO_2), the change in emissions does not exceed the applicable significance threshold. Therefore, the proposed project is not a major modification for these pollutants.

- For CO and VOCs, the change in emissions exceed their respective significance thresholds. Thus, major modification review is required for these pollutants, with the presumption that the project also causes significant net emissions increase. Note that the applicant did not provide any net emission increase analysis for these pollutants.

Thus, DEC is required and has performed the following reviews and analyses for emissions of CO and VOC for Units 5 and 6. These reviews and analyses are required for each affected new or modified emission unit causing or

[7] Section 1.1 "Bituminous and Subbituminous Coal Combustion" and Section 1.4 "Natural Gas Combustion", AP-42, EPA, and 40 CFR 98 Tables A-1 "Global Warming Potentials", C-1 "Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel" and C-2 "Default CH_4 and N_2O Emission Factors for Various Types of Fuel".

[8] Guidelines for Estimating Trace Substance Emissions from Fossil Fuel-Fired Steam Generating Plants, 2014 Technical Report.

[9] "Emission Factors for Particulate Matter from Natural Gas Combustion (xls)", Roy Huntley, EPA, 2014 NEI Documentation Site:
https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-documentation.

contributing to an emission increase of any regulated NSR pollutant equaling or exceeding its significance threshold, as per 15A NCAC 02D .0530.

- BACT analysis
- Source impact analysis
- Air quality analysis
- Additional impacts analysis

Refer to Sections 5.0 through 8.0 below for discussion of each of the above requirements of PSD.

<u>15A NCAC 02D .0536 "Particulate Emissions from Electric Utility Boilers"</u>

This regulation applies to only certain EGUs owned by Duke Energy (including former Progress Energy), which were in existence at the time it was initially promulgated (March 1983). Any new EGU such as Unit 6, which was permitted after this date, is not subject.

Unit 5 is subject to an emission standard of 0.25 lb/million Btu of particulates and 16% annual average opacity, as per the regulation. It needs to be noted that opacity limit is a state-only requirement while the mass-based particulate limit is both federal and state enforceable requirement. This EGU currently complies with these limits via annual stack testing (particulates). Continuous compliance with both mass-based and opacity limits shall be based on either COMs or CEMS (PM). Compliance is expected for both mass-based and opacity-based limits, as post project, Unit 5 is not expected to have increased particulates or visible emissions due to natural gas firing with or without coal.

<u>15A NCAC 02D .0614 "Compliance Assurance Monitoring"</u>

The Compliance Assurance Monitoring (CAM) regulation generally applies to any pollutant-specific emissions unit (PSEU) that meets the following criteria:

- The emission unit must be located at a major source for which a Part 70 or Part 71 permit is required.

- The emission unit must be subject to an emission limitation or standard.

- The emission unit must use an (active) control device to achieve compliance with the emission limitation or standard.

- The emission unit must have potential, pre-controlled emissions of the pollutant of at least 100 percent of the major source threshold.

However, there are some exemptions in regulation. For example, the rule does not apply to emission limitations or standards proposed after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act (e.g., post-1990 NSPS or NESHAP) or where a continuous compliance determination method (e.g., CEMS) is used. Unit 5 is currently subject to CAM using continuous opacity monitoring, assuring compliance with the PM limit when firing coal. Unit 6 is currently subject to CAM using control device parameter monitoring, assuring compliance with the BACT limits for sulfuric acid and condensable PM_{10} when firing coal.

This application is processed using the state construction and operation permit program in 02Q .0300 and not under the title V program in 02Q .0500; hence CAM applicability does not need to be addressed for the modified Units 5 and 6 at this time.

<u>15A NCAC 02D .0606 "Sources Covered by Appendix P of Part 51"</u>

Unit 5 is required to follow the monitoring requirements for visible emissions and sulfur dioxide as per the Appendix P of Part 51 of 40 CFR. Specifically, COMS (for visible emissions) and CEMS (for sulfur dioxide) are required to comply with the requirements therein.

When COMs is used to comply with the PM standard, the Permittee shall use a continuous opacity monitoring system (COMS) to monitor and record opacity. Continuous emissions monitoring and recordkeeping of opacity shall be performed as described in Paragraphs 2 and 3.1.1 through 3.1.5 of Appendix P of 40 CFR Part 51. The monitoring systems shall meet the minimum specifications described in Paragraphs 3.3 through 3.8 of Appendix P of 40 CFR Part 51.

The quarterly excess emissions (EE) reports required under Appendix P of 40 CFR Part 51 shall be used as an indication of good operation and maintenance of the electrostatic precipitators. These sources shall be deemed to be properly operated and maintained if the percentage of time the opacity emissions, calculated on a 6-minute average, in excess of 40 percent (including startups, shutdowns, and malfunctions) does not exceed 3.0 percent of the total operating time for any given calendar quarter, adjusted for monitor downtime (MD) as calculated below. In addition, these sources shall be deemed to be properly operated and maintained if the %MD does not exceed 2.0 percent for any given calendar quarter as calculated below.

$$\%EE = \frac{Total\ Excess\ Emission\ Time^{*}}{Total\ Source\ Operating\ Time^{***} - Monitor\ Downtime}\ x100$$

Percent Monitor Downtime (%MD) Calculation for COMS:

$$\%MD = \frac{Total\ Monitor\ Downtime^{**}}{Total\ Source\ Operating\ Time^{***}}\ x\,100$$

* Total Excess Emission Time contains any 6-minute period greater than 40% opacity including startup, shutdown, and malfunction for opacity monitoring, and any 24-hour block average that exceeds 2.3 pounds per million Btu of SO_2 measured by the CEMS including startup, shutdown, and malfunction.

** Total Monitor Downtime includes Quality Assurance (QA) activities unless exempted by regulation or defined in an agency approved QA Manual. The amount of exempt QA Time will be reported in the quarterly report as such.

*** If a source operates less than 2200 hours during any quarter, the source may calculate the %EE and/or %MD using all operating data for the current quarter and the preceding quarters until 2200 hours of data are obtained. [N.C.G.S. 143-215.110]

When PM CEMs is used (in lieu of COMs) for determining compliance with any particulate standard, the quarterly excess emissions (EE) reports shall be used as an indication of good operation and maintenance of the electrostatic precipitators. This source shall be deemed to be properly operated and maintained if the percentage of time the PM emissions, calculated on a one-hour average, greater than 0.030 pounds per million Btu heat input* does not exceed 3.0 percent of the total operating time for any given calendar quarter, adjusted for monitor downtime (MD) as calculated above, except that Total Excess Emission Time contains all one-hour periods greater than 0.030 pounds per million Btu heat input*. In addition, this source shall be deemed to be properly operated and maintained if the %MD does not exceed 2 percent for any given calendar quarter as calculated in Section 2.1.A.7.a above.

* The PM monitored value subject to the 0.030 pounds per million Btu limit may have a 5% CO_2 diluent cap, or a 14% O_2 diluent cap, substituted in the emission rate calculation for a startup or shutdown hour (as defined in §63.10042) in which the measured CO_2 concentration is below 5% or whenever the measured O_2 concentration is above 14%.

Continuous emissions monitoring and recordkeeping of sulfur dioxide emissions for Unit 5 shall be performed as described in Paragraphs 2 and 3.1.1 through 3.1.5 of Appendix P of 40 CFR Part 51.

Finally, Unit 6 is not subject to the requirements in 02D .0606 as it is subject to NSPS. As per §60.11(d), the Permittee is required to minimize emissions using good operation and maintenance practices of emission source including any control equipment, during all periods of operation including start-ups, shut-downs, and malfunctions.

<u>15A NCAC 02Q .0700 "Toxic Air Pollutant Procedures"</u>
<u>15A NCAC 02D .1100 "Control of Toxic Air Pollutants"</u>

The facility has not been previously triggered under the NC's air toxics permitting program. With this application, there are increases in emissions of certain toxics air pollutants, causing exceedance of toxic air pollutant emission rates

(TPERs) in 15A 02Q .0711. Per 02Q .0700, toxic air pollutant (TAP) compliance demonstrations are required for new or modified sources to ensure TAPs from the facility will not cause any acceptable ambient level (AAL) listed in 15A NCAC 02D.1104 to be exceeded beyond the property line. A facility-wide air toxics evaluation was performed to determine the pollutant(s) exceeding the toxic pollutant emission rate (TPER), as included in Table 4-3 below:

Table 4-3: TPER Analysis

Emission Source	**Pollutant & Emission Rate**									
	Benzene lb/yr	p-Dichlorobenzene lb/yr		Formaldehyde lb/yr		n-Hexane lb/yr		Toluene lb/yr		
Unit 5	107.8	25.1		1,579.3		37,666.2		122.1		
Unit 6	141.7	80.9		5,056.3		121,351.8		229.0		
Auxiliary Boiler #1 ES-6	-	-		278.88		-		7.52		
Auxiliary Boiler #2 ES-Aux 6	-	-		741.08		-		19.97		
Emergency Blackout Generator ES-12	3.64	-		0.37		-		1.32		
Emergency Quench Water Pump QP5	1.50	-		1.93		-		0.66		
Emergency Fire Water Pump FWP5	1.37	-		1.76		-		0.60		
Emergency Generator ES-EG6	7.94	-		0.81		-		2.87		
Emergency Fire Water Pump FWP	1.17	-		1.51		-		0.51		
Facility Total Emissions	265.08 lb/yr	105.97 lb/yr	0.012 lb/hr	7662 lb/yr	0.887 lb/hr	159,018 lb/yr	435.67 lb/day	384.52 lb/yr	1.32 lb/day	0.055 lb/hr
TPER	11.069 lb/yr	-	69.50 lb/hr	-	0.160 lb/hr	-	46.30 lb/day	-	197.960 lb/day	58.970 lb/hr
Does Facility Total Exceed TPER?	**Yes**	**No**		**Yes**		**Yes**		**No**		

As shown in the above Table,

- Benzene - Annual TPER exceeded;
- Formaldehyde - Hourly TPER exceeded;
- n-Hexane - Daily TPER exceeded.

Facility-wide modeling was conducted for the compounds listed above and the resulting modeled concentrations were compared to the applicable AALs. Then, the Permittee optimized potential emissions rates for the above pollutants to 98 percent of applicable AALs to provide a significant margin for future growth in emissions (conservative approach). These optimized emissions rates are included in Table 4-4 below:

Table 4-4: Approved Air Toxics Limits

Emission Source	**Pollutant & Emission Rate**		
	Benzene lb/yr	Formaldehyde lb/yr	n-Hexane lb/day
Unit 5	1849.3	212,047	344,762
Unit 6	2426.4	677,857	1,112,380
Auxiliary Boiler #1 ES-6	-	37404	-
Auxiliary Boiler #2 ES-Aux 6	-	99419	--
Emergency Blackout Generator	62.3	49.6	-

ES-12			
Emergency Quench Water Pump QP5	25.8	259.1	-
Emergency Fire Water Pump FWP5	23.5	236.5	-
Emergency Generator ES-EG6	136.1	108.3	-
Emergency Fire Water Pump FWP	20.1	202.4	-

Modeled emissions rates of various facility-wide sources of TAPs are associated with combustion of natural gas, no. 2 fuel oil, coal, and propane. Boiler Unit 5 TAP emissions were modeled based on 40% natural gas and 60% coal heat inputs. Boiler Unit 6 TAP emissions were modeled based on either 100% natural gas, 100% coal, or mixture of natural gas and coal heat inputs. Other point source TAP emissions modeled for the facility include two auxiliary boilers (no. 2 fuel oil/propane-fired), two no. 2 fuel oil-fired emergency generators, one diesel-fired emergency quench water pump, one diesel-fired firewater pump, and one no. 2 fuel oil-fired emergency firewater pump. Modeled TAPs emissions and release parameters were derived assuming 8,760 hours per year facility operations.

Although the air toxic emissions for sources subject to Part 63 (e.g., electric utility steam generating units (EGUs) subject to Part 63 Subpart UUUUU, engines subject to Part 63 Subpart ZZZZ) are exempt from air permitting pursuant to 02Q .0702(a)(27)(B), the Permittee has volunteered to include these emissions for all such exempt sources for compliance purposes.

The DAQ has verified the emissions factors and the methodology used to estimate emissions rates, and found them to be satisfactory. The Air Quality Analysis Branch (AQAB) has reviewed the dispersion modeling analysis for the facility and concluded on June 23, 2017 that the submitted modeling analysis adequately demonstrates compliance on a source-by-source basis.

The North Carolina Division of Air Quality's air toxics program is a "risk-based" regulatory program designed to protect the public health by limiting the emissions of toxic air pollutants from man-made sources. Because the analysis did demonstrate compliance on a source-by-source basis including emissions of exempt sources with the applicable AALs, the DAQ has concluded that the emissions from the exempt Part 63 affected sources, such as EGUs and engines, will not present an unacceptable risk to human health based on dispersion modeling. As stated above, all above sources are subject to either NESHAP Subpart UUUUU or Subpart ZZZZ. Thus, the revised permit will not include these approved air toxics emissions limits (i.e., modeled emissions rates optimized to 98 percent of respective AALs), consistent with 02Q .0702(a)(27)(B).

15A NCAC 02D .1111 "Maximum Achievable Control Technology"

Units 5 and 6 are subject to National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units pursuant to 40 CFR 63 Subpart UUUUU. The current permit includes all applicable requirements under this NESHAP for both units. No change to the existing requirements is required. It is possible that these Units may not be subject to the NESHAP for natural gas firing mode if the Permittee combusts natural gas for more than 10 percent of the average annual heat input during any 3 calendar years or for more than 15 percent of the annual heat input during any calendar year.

Reconstruction

Per §63.2, an existing facility (i.e., source) becomes a "reconstructed" facility, provided the following is met:

""Reconstruction" unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously nonaffected source to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and (2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator (or a State) pursuant to section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source."

As stated above, the project cost is 2 percent of the capital cost that would be required to construct a comparable new source (i.e., facility cost comprising of similar Units 5 and 6); thus, the project does not trigger reconstruction provision in 40 CFR 63.

15A NCAC 02D .2400 "Clean Air Interstate Rules (CAIR)"

The current permit includes the CAIR requirements in Section 2.4 for both Units 5 and 6, with respect to annual NOx (02D .2403), ozone season NOx (02D .2405), and annual SO_2 (02D .2404). These CAIR requirements were applicable to these existing electric utility steam generating units until recently. Effective February 1, 2016, these requirements have been repealed by NC. Finally, the EPA supplanted the vacated CAIR with the Cross-State Air Pollution Rule (CSAPR), which is a federal-only requirement.

In summary, the above EGUs are now subject to the CSAPR requirements. During the processing of a renewal application (8100028.14B), which is currently pending, all applicable requirements of CSAPR will be included in the air permit.

The background on these CAIR v. CSAPR is described below:

The CAIR was promulgated, addressing the interstate pollution transport under the "good neighbor" provision included in §110(a)(2)(D)(i)(I) of the CAA.

On July 11, 2008, in *North Carolina v. EPA*, the DC Circuit Court had found the EPA's CAIR illegal. The Court vacated and remanded this rule. But, on rehearing, on December 23, 2008, the Court remanded without vacatur the CAIR so that the EPA could remedy the rule consistent with the above July 2008 opinion. In brief, the DC Circuit had left the CAIR in place until the replacement of CAIR was promulgated.

On August 8, 2011 (76 FR 48208), the EPA promulgated the CSAPR, replacing the CAIR, again combating the interstate transport of air pollution under this CAA provision.

The DC Circuit on December 30, 2011 stayed the CSAPR and asked the EPA to continue implementing the CAIR.

Subsequently on merits, on August 21, 2012, the same Court in *EME Homer City Generation v. EPA*, vacated the entire CSAPR.

On April 23, 2014, the US Supreme Court in *EPA v. EME Homer City Generation*, reversed the judgement of the DC Circuit in the CSAPR (that is, upheld the CSAPR) and remanded the case back to the DC Circuit for further proceedings based on the high court's opinion on this matter.

The DC Circuit on October 23, 2014 issued an Order, lifting the stay of CSAPR.

Finally, on December 3, 2014 (79 FR 71663), EPA made changes to its regulations (such as tolling the existing deadlines) consistent with the above Order, making compliance with the CSAPR's Phase 1 and 2 requirements, starting January 1, 2015, and January 1, 2017, respectively. With respect to "sun-setting" the CAIR requirements, EPA has ruled that it will not be carrying out any functions or enforcing any requirements for any control period after December 31, 2014, for both annual and ozone season NOx, and for annual SO_2, as per §52.35(f) and §52.36(e), respectively.

15A NCAC 02D .2500 "Mercury Rules for Electric Generators"

Both units are (were) subject to this state-only requirement for mercury emissions, as per the current permit. However, effective February 1, 2016, this requirement has been repealed by NC. The applicability of this repealed requirement will be removed from the permit for both Units.

15A NCAC 2Q .0309 “Termination, Modification, and Revocation of Permits (Additional Requirements for Sulfur Dioxide and Nitrogen Oxides)”

This state-only condition limits Unit 6 NO_x emissions to 0.07 lb/million Btu, measured by a NO_x CEMS on a 30-day rolling average basis, and SO_2 emissions to 0.12 lb/million Btu, measured by an SO_2 CEMS on a 30-day rolling average basis. The NO_x emissions limit does not apply during periods of startup and shutdown, which are defined as periods when the boiler is being brought into or out of operation and the gas temperature at the SCR system is below 620 °F. Compliance with the NO_x limit will be assured via NO_x CEMS and use of the SCR post project. SO_2 emissions are expected to be below the limit when firing 100 percent natural gas or co-firing natural gas and coal in Unit 6 and the SO_2 CEMS will continue to operate and assure compliance with the above limit.

Part I Section 5.4 of S1587 (General Assembly of North Carolina Session 2005)

This is a state-only condition that requires Unit 6 to operate the advanced control technology designed to remove 99 percent of baseline SO_2 any time that electricity is being produced other than during startups. In addition, the actual emissions of SO_2 from this boiler shall not exceed 0.15 lb/million Btu as measured by CEMS on a 30-day average basis.

The Permittee has requested to modify this condition to state that operation of SO_2 control technology is not required during periods when only natural gas is being fired in Unit 6. SO_2 emissions are expected to be well below this limit when firing 100 percent natural gas in Unit 6. The SO_2 CEMS will continue to operate and assure compliance with the above limit regardless of whether the advanced controls are in operation. The DAQ will allow the Permittee to not operate the existing SO_2 control technology (FGD) when burning only natural gas in Unit 6 boiler.

15A NCAC 02Q .0400 “Acid Rain Procedures”

Units 5 and 6 are subject to the Acid Rain Program requirements with respect to sulfur dioxide and nitrogen oxide emissions, monitoring, record keeping, and reporting. The current permit includes all applicable requirements for both units. Adding natural gas capability to each of the units does not change the applicability to the Acid Rain program. During the processing of above referenced renewal application (separate application), the Acid Rain permit will also be renewed for the same duration the title V permit will be renewed.

15A NCAC 02Q .0317 “Avoidance Condition for Prevention of Significant Deterioration”

As per the current permit, to avoid applicability of PSD,

- Unit 5 (ID No. ES-5) shall not discharge into the atmosphere more than 2,465 tons per year of nitrogen oxides on a rolling consecutive 12-month period basis.

- Units 5 and 6 (ID Nos. ES-5 and ES-6) shall not discharge into the atmosphere more than 6,370 tons per year of nitrogen oxides on a rolling consecutive 12-month period basis.

- Units 5 and 6 (ID Nos. ES-5 and ES-6) shall not discharge into the atmosphere more than 25,185 tons per year of sulfur dioxide on a rolling consecutive 12-month period basis.

With the burning of natural gas in Units 5 and 6, sulfur dioxide emissions are expected to be significantly decreasing, while nitrogen oxides emissions are expected to increase negligibly. The Permittee will continue monitoring emissions of each of these pollutants using CEMS, as required, when any of these EGUs is burning natural gas alone, or in combination with coal, or solely on coal. The Permittee will also continue keeping records of emissions in a log-book monthly.

5.0 BACT Analysis

Background

The CAA §169(3) defines:

> “The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to enactment of the federal Clean Air Act Amendments of 1990.”

Given the variation between emission sources, facility configuration, local air-sheds, and other case-by-case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economic, energy, and environmental impacts are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impracticable, BACT can be defined by the use of a particular type of control device, work practice, or fuel type. In no event, can a technology be recommended which would not comply with any applicable standard of performance under CAA §§111 (NSPS) or 112 (NESHAP).

The EPA developed a guidance, commonly referred to as “Top-Down” BACT[10], for PSD applicants for determining BACT. This guidance is a non-binding reference material for permitting agencies, which process PSD applications pursuant to their SIP-approved regulations. As stated in Section 4.0 above, NCDAQ issues PSD permits in accordance with its SIP-approved regulation in 15A NCAC .02D .0530. Therefore, the DAQ does not strictly adhere to EPA's “top-down” guidance. Rather, it implements BACT in accordance with the statutory and regulatory language. As such, NCDAQ's BACT conclusions may differ from those of the EPA.

As stated above, a major modification is triggered for the project due to increases in emissions of CO and VOC. Thus, each emissions unit undergoing physical or operation change (i.e., Units 5 and 6) where the net emissions increase is projected to occur, is required to apply BACT for both CO and VOC, as per §51.166(j)(3).

The emission unit must be defined so that the BACT analysis can be performed. In this case, the Permittee has proposed to add natural gas firing capability to existing coal (fuel oil for start-ups only)-fired boilers (Units 5 and 6). Unit 5 will be burning up to 40 percent natural gas on a heat input basis with or without coal or 100 percent coal after the modification. Unit 6 will be burning 100 percent natural gas (heat input basis) or 100 percent coal (heat input basis) or any combination of these fuels. Therefore, the threshold question is whether the project consists of simply boilers or coal/natural gas-fired boilers.

As discussed in Section 3.0 above, the Permittee defines the project as coal/natural gas-fired boilers. As far as DEC is concerned, the project purpose is to provide additional fuel flexibility in the form of natural gas to its current coal burning capability. The Permittee wishes to burn either coal or natural gas, depending upon their prices (including transportation costs) and availability. In addition to the application data, during the meetings with the DAQ[11], DEC defines its project objective of fuel flexibility not only based on fuel pricing, but also based on a potential loss of single rail transportation (coal) or mining workers’ strikes crippling the availability of supply (coal). For natural gas, the Permittee considered the effects of very cold winter months, potentially restricting the availability of natural gas under the interruptible transport agreement (with PSNC) and the loss of natural gas pipeline due to unscheduled and scheduled repairs and maintenance.

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[10] “Improving New Source Review (NSR) Implementation”, J. Craig Potter, Assistant Administrator for Air and Radiation US EPA, Washington D.C., December 1, 1987, and “Transmittal of Background Statement on “Top-Down” Best Available Control Technology”, John Calcagni, Director, Air Quality Management Division, US EPA, OAQPS, RTP, NC, June 13, 1989.

[11] DAQ meetings of March 2, 2017 and June 23, 2017 with DEP and its consultant (AECOM).

In summary, the emission unit is a coal-fired boiler, proposed to add natural gas burning capability.

Applicant-Provided BACT Information on Co-firing Projects

As requested by DAQ to understand how permitting agencies have determined BACT taking into consideration the "clean fuels" provision in BACT definition, the applicant provided some examples on BACT determinations for projects consisting of co-firing of different fuels. These example determinations have been summarized for information purposes, noting that the associated permit documents have not been reviewed or verified by DAQ.

International Paper, Riegelwood, NC

The No. 5 Power Boiler at this facility is a multi-fuel fired 600 million Btu/hr boiler, which provides steam and power to the Riegelwood Mill. The boiler was originally permitted to burn coal, oil, and biomass. Permit (03138T41) contains BACT limits for several pollutants for these fuels (different BACT limits for each fuel, based on heat input). The Permittee argues that the fact that the BACT limits are different for oil, coal, and biomass operations, acknowledging no preference for use of one fuel over the other.

International Paper, Savannah, GA

The Power Boiler at this facility provides steam and power to the mill and has a heat input capacity of 1280 million Btu/hr. It was originally permitted to burn biomass (bark), pulverized coal, and fuel oil (primarily for startup). A 2014 permit application included the addition of load-bearing natural gas burners, removal of oil-firing capability, and optimization of combustion controls and the combustion air system. A BACT analysis was performed and CO BACT was determined. The BACT limit applies to any combination of fuel burning in the boiler (biomass, gas, or coal) because the boiler will burn a combination of fuels during normal operation and there were no previous BACT limits in place.

International Paper, Mansfield, LA

This mill has two multi-fuel fired 760 million Btu/hr boilers that provide steam and power to the mill. These boilers were originally permitted with BACT limits that vary based on the fuels being fired (coal, oil, or biomass) and are prorated by heat input when a combination of fuels are to be fired. The current permit includes BACT limits for several pollutants that vary based on the fuel being fired (coal, oil, gas, or biomass) and some fuels do not have BACT limits for certain pollutants (e.g., natural gas has a NOx BACT limit but not an SO_2 BACT limit). This permit demonstrates that multi-fuel boilers can have different BACT limits depending on the fuel fired and the BACT does not require the use of one fuel over another.

International Paper, Eastover, SC

This mill has two power boilers that provide steam and power to the mill. No. 1 Power Boiler (545 million Btu/hr) originally burned coal and oil and had BACT limits for several pollutants. The SO_2 BACT limits mirror the NSPS Subpart D limits (the BACT limit is pro-rated based on the heat input of coal and oil being fired). This boiler was recently converted to a gas-fired boiler to comply with the Industrial Boiler MACT. The project did not trigger PSD review and the BACT limits were not revised. No. 2 Power Boiler (500 million Btu/hr) is a multi-fuel fired boiler with SO_2 BACT limits for various fuels that are prorated based on heat input: coal, oil, and bark/tire-derived fuel. Other BACT limits that apply to this boiler are not dependent on the fuel being fired (e.g., PM).

Reliant Energy, Washington Parish Electric Generating Station, Fort Bend, TX

Units 5, 6 and 7 at this facility were originally permitted to burn coal, with natural gas fired during start-up, flame stabilization, and when coal supply is interrupted. The units were re-permitted to allow co-firing natural gas with coal and to increase the permitted capacity to 7,400 million Btu/hr for Units 5 and 6 and 6,750 million Btu/hr for Unit 7. The new permit for each unit established BACT emission limits for CO when firing coal only and when co-firing natural gas with coal. The new permit for each unit also established LAER limits for VOC when firing coal only and when co-firing natural gas with coal.

In summary, the Permittee concludes that different approaches can be applied to establish BACT for boilers co-firing multiple fuels and BACT can accommodate firing various fuels without a restriction on the type of fuel allowed to be burned at any one time.

BACT Analysis for CO

CO is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time, mixing, and temperature in the combustion zone to ensure complete combustion. These factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (e.g., low-NOx burners) can result in higher levels of CO emissions. Thus, generally, a compromise is established whereby the combustion conditions are set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

Potential CO control alternatives include exhaust gas cleanup methods such as thermal oxidation and catalytic oxidation, and front-end method such as combustion control wherein CO formation is suppressed within the combustor.

<u>CO Control Alternatives</u>

Good Combustion Control

Implementation of proper burner design and optimization of combustion air systems to achieve good combustion efficiency in boilers will minimize the generation of CO. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, are essential elements of a boiler operating with low CO emissions. If a boiler is operated improperly or is not well-maintained, the resulting CO emissions (and organic compounds emissions) can increase significantly. To minimize CO emissions from properly operated utility boilers, no auxiliary equipment is needed. Additionally, complete fuel combustion is a desired operating scenario leading to an increased boiler efficiency.

Good combustion control is concluded to be a technically feasible option for Units 5 and 6.

Thermal Oxidation

Thermal oxidation can be used to oxidize CO to carbon dioxide and water by passing exhaust gas through a burner flame zone to combust remaining carbon compounds. Thermal oxidizers typically operate at temperatures of 1,500°F or higher to achieve control efficiencies of up to 95 percent or higher.

When CO is oxidized in the presence of sulfur compounds during coal combustion, the downstream air pollution control equipment can be damaged by sulfuric acid formation. The coal combustion in Units 5 and 6 will continue after this project. Thus, high levels of sulfur compounds emissions (SO_2, SO_3) will be present if the thermal oxidizer is located prior to the FGD, which can result in formation of significant amount of sulfuric acid mist emissions. In addition, if the thermal oxidizer is installed downstream of the existing FGD, the auxiliary fuel required to reheat the exhaust gas stream will generate additional undesirable increases in emissions of NO_X and CO_2.

For the above reasons, thermal oxidation has been concluded a technically infeasible option for Units 5 and 6.

Catalytic Oxidation

Catalytic oxidation technology has been used to reduce both CO and VOC emissions for natural gas- and ultra-low sulfur diesel-fired boilers, but not for coal-fired boilers. It can achieve CO reductions as high as 95 percent and VOC reductions up to 70 percent. The catalyst consists of platinum group metals embedded within a wash-coat applied to a metallic honeycomb support substrate.

The CO oxidation catalyst functions in the same operating temperature regime required for achieving NO_X control using selective catalytic reduction, requiring installation of the CO catalytic oxidation equipment upstream of the particulate and sulfur control devices. This leaves the catalyst bed highly susceptible to plugging from particulate matter, as well as poisoning if sulfur compounds and other metals are present in the exhaust gases.

DEC states that, as per Johnson Matthey, the company responsible for inventing oxidation catalyst technology, the catalytic oxidation option for CO emission control is not technically feasible for coal-fired boilers, due to physical and chemical poisoning of the catalyst that occurs from the coal combustion exhaust. With respect to feasibility of catalytic oxidation system for controlling NOx emissions (SCR system), the Permittee contrasts that the CO catalyst is different from the NOx catalyst, because the area available for flue gas flow for the CO catalyst is much smaller than the NOx catalyst.

Units 5 and 6 will remain coal-fired boilers following the project, with the ability to fire natural gas in combination with coal. In summary, the particulate matter and sulfur compounds present in the exhaust gases from coal combustion make catalytic oxidation technically infeasible for controlling CO emissions from Unit 5 or Unit 6.

Energy, Environmental, and Economic Impacts

The only feasible control remaining for emissions of CO is good combustion control. There are no adverse impacts associated with the use of good combustion control with respect to the standpoints of energy, economic, and environmental.

BACT Determination

The DAQ has reviewed the RBLC[12] data for time-period (2012-present) for natural gas and coal-fired EGUs, with respect to emissions of CO and VOC. It provides relevant information on BACT determinations from various permitting authorities in recent years to help determine the type of technology and/or associated limitation for units with similar design (tangentially fired or wall fired pulverized coal / natural gas fired steam electric generating units) and heat input rates greater than 250 million Btu/hr. It should also be stated that the Permittee has reviewed the same database for a longer period (2006 through present)[13] to capture more determinations and obtain more data on the same attributes (type of technology and emission limitation) for natural gas/coal-fired EGUs.

[12] RACT/BACT/LAER Clearinghouse.

[13] Response to June 29, 2017 Additional Information Request for Application No. 8100028.16B, Duke Energy Carolinas, LLC, Cliffside Steam Station, Title V Permit 04044T39, Facility ID 8100028, Duke Energy, Carolinas, July 7, 2017.

Table 5-1: DAQ-Analyzed Data

Duke Energy Carolinas, LLC

Cliffside Steam Station

RBLC Data (2012-Present) Summary for CO Emissions from Natural Gas-Fired Electric Utility Boilers (> 250 million Btu/hr)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
FL-0344	OKEELANTA COGENERATION PLANT	8/27/2013	Natural Gas Boiler	589	MMBTU/H	Overfire air and proper combustion	0.08	LB/MMBTU	BACT-PSD	U
FL-0334	ANCLOTE POWER GENERATING FACILITY	9/14/2012	Fossil Fuel Fired Steam Generators	556.2	MW	Good combustion practices	0.15	LB/MMBTU	BACT-PSD	U
OK-0150	PSO SOUTHWESTERN POWER STATION	1/17/2013	BOILER	3290	MMBTU/H	-	0.15	LB/MMBTU	BACT-PSD	U
IA-0109	CITY OF AMES STEAM ELECTRIC PLANT	7/28/2015	Boiler 7	476	MMBTU/H	Good combustion practices	0.2	LB/MMBTU	BACT-PSD	U
IA-0109	CITY OF AMES STEAM ELECTRIC PLANT	7/28/2015	Boiler 8	775	MMBTU/H	Good combustion practices	0.2	LB/MMBTU	BACT-PSD	U
OK-0161	PSO SOUTHWESTERN POWER STA	3/31/2014	Boiler #3	3290	MMBTU/H	-	0.465	LB/MMBTU	BACT-PSD	Y
OK-0168	SEMINOLE GNRTNG STA	5/5/2015	NATURAL GAS-FIRED BOILER	16456	MMBTU/H	Good combustion practices	0.465	LB/MMBTU	BACT-PSD	U

U = Unknown

Y = Yes

The DAQ findings as summarized in Table 5-1 above indicate a total of seven BACT determinations in the database for natural gas-fired EGUs within the prescribed timeframe. There are no determinations for coal-fired EGUs. Five of the seven determinations include good combustion control, while the remaining two do not list the type of control method. The emission limits range between 0.08 lb/million Btu and 0.465 lb/million Btu. In addition, there is not any determination with BACT requiring the use of catalytic oxidizer.

DEC has proposed a CO BACT when burning natural gas alone or co-firing coal to be 0.08 lb/million Btu with an averaging period of 6-hours, using good combustion control for Unit 5 boiler, for all operations except start-ups and shutdowns. This proposed BACT is equivalent to the lowest CO limit RBLC. DEC emphasizes that Unit 5, a tangential-fired boiler, can achieve a low CO emission rate due to mixing in the combustion zone, provided through swirling motion created by burner arrangement.

However, with Unit 6, DEC argues that unlike Unit 5, it is a wall-fired boiler, which has generally an intrinsically higher CO emission rate than the tangentially-fired boiler. As an evidence, it points to emissions factors for natural gas-fired boilers: 84 lb/million ft^3 (wall-fired) v. 24 lb/million ft^3 (tangentially-fired)[14]. Thus, DEC states that Unit 6 is not capable of achieving the low emission rate as Unit 5.

As indicated above, the lowest emission limit in the recent RBLC data, is 0.08 lb/million Btu; however, as per the Permittee, this limit is associated with a tangentially-fired boiler[15] which was never constructed. The next lower CO limit is 0.084 lb/million Btu (based on Permittee's search of RBLC); but that is associated with a tangentially-fired boiler using an oxidation catalyst[16]. DEC argues that the Unit 6 boiler is a wall-fired boiler. Moreover, it is not technically feasible to install an oxidation catalyst on coal-fired boilers as discussed above.

The next lower CO BACT comprises of 0.15 lb/million Btu, using good combustion control[17], as per the Permittee and confirmed in the above table. However, the Permittee has proposed a BACT of 0.12 lb/million Btu with an averaging period of 6 hours, using good combustion control, when burning either natural gas alone or in combination with coal, for all operations except during start-ups and shutdowns. This proposed BACT is based upon boiler design and considering the expected performance.

For both Units 5 and 6, for periods of startups and shutdowns of Units 5 and 6, the Permittee proposes work practice standards, similar to the standards listed in Table 3 to 40 CFR 63 Subpart UUUUU (MATS), as BACT. These work practice standards are appropriate as they in fact represent good combustion control practices. The proposed requirements as BACT during startups and shutdowns are as follows:

> For startup of a unit, you must use clean fuels as defined in §63.10042 for ignition. Once you convert to firing coal, you must engage all the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation.
>
> While firing coal during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
>
> Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be

[14] Section 1.4 "Natural Gas Combustion", 7/98, AP-42, EPA.
[15] Okeelanta Cogeneration Plant, FL-0344, 8/27/2013 (permit issuance date) and DEC Communication with FL DEP.
[16] Montville Power LLC, CT-0156.
[17] Anclote Power Generating Facility, FL-0334, 9/14/2012 (permit issuance date).

used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I (“Subpart I-Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel”).

After careful consideration, the DAQ proposes to approve 0.08 lb/million Btu based on 6-hour average, using good combustion control, as BACT for Unit 5, when burning natural gas or natural gas in combination with coal, for all operations except startups and shutdowns. The DAQ also proposes to approve 0.12 lb/million Btu on a 6-hour averaging basis, using good combustion control, as BACT for Unit 6 when burning solely natural gas or natural gas in combination with coal, for all operations except startups and shutdowns. The above BACT for both units will be verified through annual stack testing. Good combustion practices include maintaining a proper excess air level, performing periodic observations of flame pattern, periodic burner inspections, annual stack testing and performing regular tune-ups.

For operations during startups and shutdowns, regardless of the type of fuel burned, the DAQ proposes to approve work practice standards as detailed above.

BACT Analysis for VOC

VOC emissions are generated from boilers because of incomplete fuel combustion. Operating conditions such as lower than optimal temperatures, insufficient residence time, and lower than optimal oxygen levels due to inadequate mixing and/or a low air-to-fuel ratio in the combustion zone will increase VOC emissions. Trace amounts of VOC species in natural gas fuel (e.g., formaldehyde and benzene) can also contribute to VOC emissions if they are not completed combusted in boiler.

Potential VOC control alternatives include exhaust gas cleanup methods such as thermal oxidation and catalytic oxidation, and front-end method such as combustion control wherein CO formation is suppressed within the combustor.

<u>VOC Control Alternatives</u>

Good Combustion Control

Implementation of proper burner design and optimization of combustion air systems to achieve good combustion efficiency in boilers will help minimize VOC emissions. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, are essential elements of a boiler operating with low VOC emissions. To minimize VOC emissions from properly operated utility boilers, no auxiliary equipment is needed. As per the Permittee, this approach was confirmed as MACT when EPA promulgated a work practice standard (tune-up) for organic HAP emissions from utility boilers in MATS because the significant majority of data for measured organic HAP emissions from EGUs were below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs were considered.

Good combustion control is concluded to be a technically feasible option for Units 5 and 6.

Thermal Oxidation

Thermal oxidation can be used to oxidize VOC to carbon dioxide and water by passing exhaust gas through a burner flame zone to combust remaining carbon compounds. Thermal oxidizers typically operate at temperatures of 1,500°F or higher to achieve control efficiencies of up to 95 percent or higher.

When VOC is oxidized in the presence of sulfur compounds during coal combustion, the downstream air pollution control equipment can be damaged by sulfuric acid formation. The coal combustion in Units 5 and 6 will continue after this project. Thus, high levels of sulfur compounds emissions (SO_2, SO_3) will be present if the thermal oxidizer is located prior to the FGD; thus, resulting in formation of significant amount of sulfuric acid mist emissions. In addition, if the thermal oxidizer is installed downstream of the existing FGD, the auxiliary fuel required to reheat the exhaust gas stream will generate additional undesirable increases in emissions of other pollutants, NO_X and CO_2.

For the above reasons, thermal oxidation is a technically infeasible option Unit 5 and Unit 6.

Catalytic Oxidation

Catalytic oxidation technology has been used to reduce both VOC and CO emissions for natural gas-fired boilers. It can achieve VOC reductions up to 70% and CO reductions as high as 95%. The catalyst consists of platinum group metals embedded within a wash coat applied to a metallic honeycomb support substrate.

The oxidation catalyst functions in the same operating temperature regime required for achieving NO_X control using selective catalytic reduction; thus, requiring installation of the VOC catalytic oxidation equipment upstream of the particulate and sulfur control devices. This leaves the catalyst bed highly susceptible to plugging from particulate matter, as well as catalyst poisoning if sulfur compounds and other metals are present in the exhaust gases.

DEC states that, as per Johnson Matthey, the company responsible for inventing oxidation catalyst technology, the catalytic oxidation option for VOC emission control is not technically feasible for coal-fired boilers, due to physical and chemical poisoning of the catalyst that occurs from the coal combustion exhaust. With respect to feasibility of catalytic oxidation system for controlling NOx emissions (SCR system), the Permittee contrasts that the VOC catalyst is different from the NOx catalyst, because the area available for flue gas flow for the oxidation catalyst for VOC control is much smaller than the NOx catalyst.

Units 5 and 6 will remain coal-fired boilers following the project, with the ability to fire natural gas in combination with coal. In summary, the particulate matter and sulfur compounds present in the exhaust gases from coal combustion make catalytic oxidation technically infeasible for controlling VOC emissions from Unit 5 or Unit 6.

<u>Energy, Environmental, and Economic Impacts</u>

The only feasible control remaining for emissions of VOC is good combustion control. There are no adverse impacts associated with the use of good combustion control with the standpoints of energy, economic, and environmental impacts.

<u>BACT Determination</u>

The DAQ has reviewed the RBLC[18] data for time-period (2012-present) for natural gas and coal-fired EGUs, with respect to emissions of CO and VOC. It provides relevant information on BACT determinations from various permitting authorities in recent times to help determine the type of technology and/or associated limitation for units with similar design (tangentially fired or wall fired pulverized coal / natural gas fired steam electric generating units) and heat input rates greater than 250 million Btu/hr. It should also be stated that the Permittee has reviewed the same database for a longer period (2006 through present) to capture more determinations and obtain more data on the same attributes (type of technology and emission limitation) for EGUs.

Based on DAQ findings, there is not any VOC BACT determination in the above time-period in the RBLC database for natural gas or coal fired boilers. When looking beyond this period, as per the Permittee, there is one BACT determination (CT-0156 as cited above) which includes a limit of 0.0055 lb/million Btu using oxidation catalyst; however, this boiler does not burn coal at all. As stated above, both Units located at Cliffside facility can burn coal after the project. In addition, catalytic oxidation has been deemed to be technically infeasible for coal firing as discussed above. Thus, for Units 5, the Permittee has proposed 0.0055 lb/million Btu, using good combustion control, as BACT when burning natural gas solely or in combination with coal, for all operations except start-ups and shutdowns.

For Unit 6 as well, the Permittee proposes an emission limitation of 0.0055 lb/million Btu using good combustion control as BACT, when burning natural gas only, for all operations except start-ups and shutdowns.

[18] Id. at 19.

For co-firing operations for Unit 6, the Permittee proposes a pro-rated emission limit as BACT based on heat input of coal and natural gas (6-hour average) and using the current coal only BACT of 0.003 lb/million Btu and the proposed BACT as above for natural gas only, as follows:

$E_{cg} = (E_c * Q_c + E_g * Q_g)/Q_t$

Where:
E_{cg} = BACT limit for coal and natural gas co-firing, lb/million Btu
E_c = 0.003 lb/million Btu (current BACT for coal firing)
E_g = 0.0055 lb/million Btu (proposed BACT for natural gas firing)
Q_c = coal heat input in million Btu
Q_g = natural gas heat input in million Btu
$Q_t = Q_c + Q_g$

For both Units 5 and 6, during periods of startups and shutdowns of Units 5 and 6, for reducing emissions of VOCs, the Permittee proposes work practice standards, similar to the standards listed in Table 3 to 40 CFR 63 Subpart UUUUU (MATS), as BACT. These work practice standards are appropriate as they represent good combustion control practices. The proposed requirements as BACT during startups and shutdowns are as follows:

> For startup of a unit, you must use clean fuels as defined in §63.10042 for ignition. Once you convert to firing coal, you must engage all the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation.
>
> While firing coal during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in §63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.
>
> Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) oil, including those fuels meeting the requirements of 40 CFR part 80, subpart I ("Subpart I-Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel").

After considering the above, the DAQ proposes to approve 0.0055 lb/million Btu using good combustion control, based on 6-hour average, as BACT for Unit 5 when burning natural gas with or without coal for all operations, except start-ups and shutdowns.

For Unit 6 also, the DAQ proposes to approve 0.0055 lb/million Btu using good combustion control, based on 6-hour average, as BACT, when burning natural gas only, for all operations except start-ups and shutdowns. For co-firing of natural gas with coal, the DAQ proposes to approve the BACT using good combustion control, established on a pro-rated basis as above, for all operations except start-ups and shutdowns. The above BACT for both units will be verified through annual stack testing. Good combustion practices include maintaining a proper excess air level, performing periodic observations of flame pattern, periodic burner inspections, annual stack testing and performing regular tune-ups.

For operations during startups and shutdowns, regardless of the fuel type, the DAQ proposes to approve work practice standards as specified above as BACT.

BACT Summary

The following Table 5-4 summarizes the DAQ proposed BACT for the modified Units 5 and 6:

Table 5-4: BACT Summary

EMISSION SOURCE	POLLUTANT	BACT Natural Gas Only or Natural Gas and Coal Co-firing	CONTROL DESCRIPTION
Unit 5 (ID No. ES-5)	CO	0.08 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control
Unit 6 (ID No. ES-6)	CO	0.12 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control
Units 5 and 6 (ID Nos. ES-5 and ES-6)	CO	Work practice standards during start-ups and shutdowns – Section 2.2 C. 3.b.i. through iii.	Work practices
Unit 5 (ID No. ES-5)	VOC	0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs	Good combustion control
Unit 6 (ID No. ES-6)	VOC	Natural Gas Only 0.0055 lb/million Btu (6-hour average), all operations except start-ups and shut-downs Natural Gas and Coal Co-firing $E_{gc} = (E_g * Q_g + E_c * Q_c)/Q_t$ (6-hour average), all operations except start-ups and shut-downs Where: E_{gc} = BACT for natural gas and coal co-firing, lb/million Btu E_g = 0.0055 lb/million Btu E_c = 0.003 lb/million Btu Q_g = natural gas heat input in million Btu Q_c = coal heat input in million Btu $Q_t = Q_g + Q_c$	Good combustion control
Units 5 and 6 (ID Nos. ES-5 and ES-6)	VOC	Work practice standards during start-ups and shutdowns – Section 2.2 C. 3.b.i. through iii.	Work practices

6.0 Air Quality Analysis

§51.66(m)(1) requires that the major modification application for a PSD permit include an analysis of the ambient air quality of the area where the source is located for any regulated NSR pollutant exceeding the significant net emissions increase. This analysis is called "pre-application analysis" (generally called the "preconstruction monitoring" requirement). For pollutants with associated NAAQS, the application must include 1 year of continuous monitoring data from the date of the receipt of the complete application. The permitting agency may accept ambient monitoring data for a shorter duration but data cannot be for less than 4 months. For pollutants for which no NAAQS exist, the permitting authority can require an analysis containing such data as it determines appropriate to assess the ambient air quality in the area in which the source is located.

§51.66(m)(2) includes that the owner or operator of a major modification shall, after construction of such modification, conduct such ambient monitoring as the permitting authority determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having, on air quality in any area. This monitoring is called "post-construction monitoring".

However, §51.666(i)(5) includes that permitting authority may exempt any major modification from the requirements of §51.166(m), with respect to monitoring for a specific pollutant, if net emissions increase of the pollutant from a modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m^3, 8-hour average;
Nitrogen dioxide - 14 ug/m^3, annual average;
$PM_{2.5}$ - 0 µg/m^3, 24-hour average;
PM_{10} -10 µg/m^3, 24-hour average;
Sulfur dioxide - 13 ug/m^3, 24-hour average;
Lead - 0.1 µg/m^3, 3-month average.
Fluorides - 0.25 µg/m^3, 24-hour average;
Total reduced sulfur - 10 µg/m^3, 1-hour average
Hydrogen sulfide - 0.2 µg/m^3, 1-hour average; and
Reduced sulfur compounds - 10 µg/m^3, 1-hour average

The above concentration values are called “significant monitoring concentrations (SMC)”.

In addition, for ozone, no *de minimis* air quality level (i.e., SMC) has been provided. As per EPA, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data.

The same provision includes some more exemptions from this air quality analysis requirement (both “preconstruction monitoring” and “post-construction monitoring”) for the source (i.e., applicant) as follows: (i) If any regulated NSR pollutant is not listed with the associated impact level (i.e., SMC), or (ii) the concentrations of the pollutant in the area that the major modification would affect is less than the associated SMC.

As stated above, this major modification review is for CO and VOC, based on the associated net significant emissions increase. As stated below in Section 7.0, the predicted air quality impact of CO is much less than the associated impact level (SMC). Hence, no ambient monitoring (both pre- and post-construction) for CO may be required for this major modification.

For ozone NAAQS, the net significant emissions of VOCs are greater than 100 tons per year. Refer to Section 7.0 below for further details.

7.0 Source Impact Analysis

An air quality preliminary impact analysis was conducted for CO for which Class II Area Significant Impact Levels (SIL) have been established by EPA through policy. The modeling results were compared to the applicable Class II Area SIL (See Table 7-1 below) to determine if a full impact air quality analysis would be required for that pollutant.

The modeling was based on maximum emissions and associated stack release parameters for Boiler Units 5 and 6. The highest CO potential emission rate was modeled for each boiler for added conservatism.

Table 7-1: Class II Significant Impact Results (µg/m^3)

Pollutant	Averaging Period	Project Maximum Impact	Class II Significant Impact
CO	8-hour	48	500
	1-hour	128	2000

Class II Area Full Impact Air Quality Analysis for CO

A modeling analysis demonstrating compliance with NAAQS for CO is not required because predicted impacts of project CO emissions are less than the applicable 8-hour and 1-hour SILs as shown above.

Ozone Impact Analysis

As discussed elsewhere in this preliminary determination, the project VOC emissions of 124 tons per year exceed the ozone SER of 40 tons per year for VOCs. Therefore, project VOC emissions impacts on ambient ozone levels were analyzed following a qualitative approach. The qualitative approach included analysis of data taken from NO_X and VOC emission inventories, available ozone monitoring data, and review of creditable photochemical ozone modeling representative of the project area.

NOx and VOC emission inventories from 2011 were compiled from several counties that would potentially be affected by project VOC emission increases: Rutherford County, Cleveland County, Mecklenburg County, Lincoln County, and Cherokee County, South Carolina. Total emissions for each county were partitioned by the following sectors: industrial sources, fuel combustion sources, mobile sources, and biogenic sources. The project VOC emissions of 124 tons per year amounted to approximately 1% of Rutherford and Cleveland Counties VOC emissions totals. Project VOC emissions were shown to be 0.1% of VOC emissions from all counties combined. In terms of total VOC emissions, the project VOC emissions contributions to ozone production in the project area and surrounding counties are expected to be minimal.

Ozone monitoring data for the 2013-2015 period were compiled from nearby stations located in Mecklenburg County, Lincoln County, and Cherokee County, South Carolina. The 8-hour ozone design concentrations observed at these stations during 2013-2015 period ranged from 63 ppb in Cherokee County to 68 ppb in Mecklenburg County. All 8-hour ozone design concentrations were less than the ozone NAAQS of 70 ppb.

Review of available EPA photochemical ozone modeling for the southeast was conducted to provide qualitative insight into the relationship between VOC emissions and ozone impacts for the project area. EPA recently published draft guidance in December 2016 that includes summarized results from photochemical ozone modeling of 276 hypothetical sources with varying stack and emissions parameters located throughout the country.[19] Maximum 8-hour ozone concentrations from sources emitting at the 500 tons per year VOC level range from 0 ppb to 0.46 ppb. This range in 8-hour ozone concentrations includes sources modeled in the western, central, and eastern conterminous U.S. The range of 8-hour ozone concentrations were 0.01 ppb to 0.39 ppb for emission sources with tall stacks located in the eastern U.S. By comparison, project VOC emissions of 124 tons per year are expected to contribute even less to 8-hour ozone concentrations within the affected project area. Assuming a linear relationship between modeled VOC emissions and predicted ozone concentrations from the eastern U.S. modeling, project VOC emissions are conservatively expected to increase 8-hour ozone concentrations by, at most, 0.1 ppb. Therefore, based on available photochemical modeling for the project area, project VOC emissions are expected to have negligible impacts on ozone such that further refined modeling analysis is not required.

8.0 Additional Impact Analysis

Additional impact analyses were conducted for growth, soils and vegetation, and visibility impairment.

Growth Impacts

No secondary growth is proposed for the project.

Soils and Vegetation

[19] Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 12 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program. December 2016. EPA-454/R-16-006.

The project impact on soils and vegetation was analyzed by comparing the maximum modeled 1-hour (128 µg/m^3) and 8-hour (48 µg/m^3) CO concentrations to screening thresholds recommended in EPA's "A Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA-450/2-81-078). The modeled concentrations were well below the 1-week screening threshold of 1,800,000 µg/m^3. Therefore, little or no significant impacts are anticipated from the project to soils and/or vegetation.

Class II Visibility Impairment Analysis

The Class II visibility analysis was not required given the project emissions do not include significant amounts of visibility-impairing pollutants such as NO_X, SO_2, $PM_{2.5}$, or PM_{10}. Additionally, the project is not located within 10 km of an area protected from visibility impairment. Therefore, NC DAQ did not require the Class II Visibility Impairment Analysis.

9.0 Class I Increment/Air Quality Related Values (AQRV) Regional Haze Impact and Deposition Analyses

The project does not include significant emissions of any pollutant with an established Class I Area Increment or Deposition Analysis Threshold. The project also does not include significant emissions of any visibility-impairing pollutant such as NO_X, SO_2, $PM_{2.5}$, or PM_{10}. Therefore, analysis of project impacts on Class I Area Increments, deposition, or visibility was not required.

10.0 Facility Wide Air Toxics

Refer to Section 4.0 above.

11.0 Facility Emissions Review

The following table includes the facility wide actual emissions as reported to DAQ for calendar year 2015.

Pollutant	**Actual Emissions** tons/year
Particulate (TSP)	207.43
Particulate (PM-10)	178.96
Particulate (PM-2.5)	158.60
Carbon Monoxide	541.01
Nitrogen Oxides	1,176.38
Sulfur Dioxide	617.26
Volatile Organic Compounds	12.90
GHG as CO_2e	ND
Single largest HAP	9.98 (Hydrogen Chloride)
Total HAPs	16.29

ND = No data

12.0 Public Notice/EPA and Affected State(s) Review

This permit application's processing is to conform to the public participation requirements pursuant to both 15A NCAC 0530 "Prevention of Significant Deterioration" and 15A NCAC 02Q .0300 "construction and operation permits".

A public notice (See Appendix 1 below) for the availability of preliminary determination and the draft Title V will be published in a local newspaper of general circulation for 30 days for review and comments. A copy of the public notice will be provided to the EPA, and all local and state authorities having authority over the location at which the proposed modification is to be constructed. Draft permit documents will also be provided to EPA, affected states, and all interested persons in mailing list, maintained by the DAQ. Finally, all documents will be placed on the DEQ's website and a complete administrative record for the draft permit documents will be kept for public review at the DEQ's Asheville Regional Office for the entire public notice period (30 days).

As this application is not processed pursuant to 15A NCAC 02Q .0500 "Title V procedures", none of the public participation requirements contained therein apply to the application.

Finally, Appendix 2 below, includes listing of both entities and associated documents to be sent for the proposed PSD major modification, satisfying the requirements in §51.166(q) "public participation".

13.0 Stipulation Review

The following changes were made to the Duke Energy Carolinas, LLC, Air Quality Permit No. 04044T40:

Old Page No. [Air Permit No. 4044T40]	**New Page No.** [Air Permit No. 04044T41]	**Condition No.**	**Changes**
3 9 41 80	3 9 41 79	Section 1 Table Section 2.1 A. Section 2.1 J. Section 2.2 C.	Include natural gas burning capability for both Units 5 and 6.
9	9	Section 2.1 A. Table	Clarify NOx emission standards also apply during natural gas burning under 02D .0519. Remove applicability of mercury rule under 02D .2500, as this regulation has been repealed. Include applicability of 02D .0530 (PSD) for CO and VOCs (natural gas only or natural gas and coal co-firing). Include a requirement of 2nd step application for a two-step 02Q .0501(c)(2) procedure [02Q .0504].
11	12	Section 2.1 A.1.g.	Clarify that the Permittee does not have to operate the FGD when burning natural gas only.
11	12	Section 2.1 A.2.a. and c.	Clarify NOx emission standards also apply during natural gas burning under 02D .0519.
18	-	Section 2.1 A.8.	Remove applicability of mercury rule under 02D .2500, as this regulation has been repealed.
41	41	Section 2.1 J. Table	Remove applicability of NOx emission standards under 02D .0519 as it is not applicable (because the boiler is subject to NOx standard in NSPS Subpart Da). Remove applicability of mercury rule under 02D .2500, as this regulation has been repealed. Include applicability of 02D .0530 (PSD) for CO and VOCs (natural gas only or natural gas and coal co-firing). Include a requirement of 2nd step application for a two-step 02Q .0501(c)(2) procedure [02Q .0504].
48	48	Section 2.1 J.3.a.	Clarify that the Permittee does not have to operate

			the FGD when burning natural gas only.
49	-	Section 2.1 J.5.	Remove applicability of NOx emission standards under 02D .0519 as it is not applicable (because the boiler is subject to NOx standard in NSPS Subpart Da).
49	-	Section 2.1 J.6.	Remove applicability of mercury rule under 02D .2500, which has been repealed.
-	86	Section 2.2 C.3.	Include a new requirement under PSD for both Units 5 and 6 for CO and VOCs (natural gas only or natural gas and coal co-firing).
-	88	Section 2.2 C.4.	Include a new requirement: 2nd step application requirement for Units 5 and 6 within 12 months of commencement of burning natural gas in either Unit 5 or Unit 6.

14.0 Conclusions, Comments, and Recommendations

- The application does not include any approval for a new air pollution capture and control system or a modification to an existing control device equipment; so, the requirements in 02Q .0112 “applications requiring professional engineer seal” do not apply.

- The proposed project is neither a “new facility” nor an “expansion of [the] existing facility”. Hence, consistency determination is not required in accordance with 2Q .0304(b)(1).

- The draft permit (pre-public notice version) was sent to the regional office for review on xx.

- The draft permit (pre-public notice version) was sent to the Permittee for review on xx.

- This engineer recommends issuing the revised permit after the completion of public comment and EPA review periods.

Appendix 1

Public Notice

Appendix 2

Listing of Entities and Associated Documents To be Sent

NEWSPAPER	Ms. Erica Meyer The Daily Courier 601 Oak Street Forest City, NC 28043 (828) 202-2924 emeyer@thedigitalcourier.com	Public Notice
OFFICIALS	Mr. Steve Garrison Manager, Rutherford County 289 North Main Street Rutherfordton, NC 28139 (828) 287-6060	Public Notice
SOURCE	Mr. David Barnhardt Manager Cliffside Steam Station Duke Energy Carolinas, Inc. 573 Duke Power Road Mooresboro, NC 28114 (828) 657-2001	Preliminary Determination, Draft Permit & Public Notice
EPA	Ms. Heather Ceron Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, Georgia 30303-3104 (404) 562-9185	Preliminary Determination, Draft Permit & PublicNotice
	Preliminary Determination, Draft Permit, and Public Notice, via electronic mail to: ceron.heather@epa.gov with cc to: shepherd.lorinda@epa.gov	
FLM	Ms. Jill Webster Branch of Air and Water Resources US Fish and Wildlife Service 7333 W. Jefferson Avenue, Suite 375 Lakewood, CO 80235-2017 (303) 914-3804	None
ASHEVILLE REGIONAL OFFICE	Mr. Brendan Davey NC DAQ Air Quality Regional Supervisor 2090 U.S. Highway 70 Asheville, NC 28778 (828) 296-4500	Preliminary Determination, Draft Permit, Public Notice & Application